RESPONSIVE SUMMARY FOR STATE IMPLEMENTATION PLAN REVISION:

Revisions to the Arkansas State Implementation Plan
Regional Haze SIP Revision for the 2018 – 2028 Planning Period

Pursuant to Arkansas Code Annotated (Ark. Code Ann.) § 8-4-317(b)(2)(B)(i), the Arkansas Department of Energy and Environment's Division of Environmental Quality (DEQ) must prepare a record of the public process in the form of a written response to each issue raised during the public comment period for a proposed state implementation plan (SIP) revision. A responsive summary groups public comments into similar categories and explains why DEQ accepts or rejects the rationale for each category.

On February 27, 2022, DEQ released the proposed Regional Haze SIP for Planning Period II ("the proposed SIP") for public review and comment. The public comment period ended on April 28, 2022. DEQ received comments from six commenters.[1] Comments received during the public comment period are summarized and a response for each is provided below. Complete comments received by DEQ are available online here at https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx and have been included with this submittal.

A. Evaluation of Existing Emission Limits and Control Measures

Comment 1:

One commenter suggested including in the proposed SIP narrative the existing emission limits for SO_2 and NOx and where those are located (SIP, permit, etc.) for sources undergoing four-factor analyses.

Response 1:

DEQ will include existing emission limits for each evaluated emission unit and where these are located. See Chapter V.

Comment 2:

One commenter suggested discussing how existing limits for sources undergoing four-factor analyses compare to the baseline emissions used in the four-factor analysis.

[1] Complete comments received by DEQ are available online here: https://www.adeq.state.ar.us/air/planning/sip/regional-haze.aspx DEQ has summarized and grouped similar comments for this responsive summary.

Response 2:

Existing emission limits may not be directly comparable to baseline actual emissions used for the four-factor analyses. DEQ includes a summary of total allowable emissions at the beginning of each permit. However, the summary itself is not a permit condition. Emission limits may come in multiple forms, including pound per hour (lb/hr), pounds per million metric British thermal units (lb/mmBtu), etc. The annual emissions based on these limits will vary based on unit operations and variations in fuel supply. Therefore, the suggested discussion does not provide additional support to the policy decisions contained in the proposed SIP.

No changes to the proposed SIP are necessary in response to this comment.

Comment 3:

Two commenters suggested that if DEQ determines no additional measures are necessary for an emission unit to make reasonable progress for a particular source, DEQ should evaluate whether the source's existing measures are necessary to make reasonable progress. If so, these existing measures should be included in the SIP as part of the state's long-term strategy (commenters cite to the July 8, 2021 EPA "clarifications" guidance memo).

Response 3:

DEQ disagrees in principle with the interpretation of the Regional Haze Rule contained in the July 8, 2021 memo regarding inclusion of existing measures in the SIP. Adoption of such an approach would not generate any emissions reductions to further progress toward natural visibility conditions. At best, it would serve as a backstop to prevent an emissions increase that may or may not measurably affect visibility conditions at federal Class I areas. DEQ's approved SIP already contains provisions that achieve this purpose as part of the permitting process. Each of the facilities evaluated under the reasonable progress factors meet the definition of major stationary source and are subject to the SIP-approved prevention of significant deterioration (PSD) requirements in Arkansas Pollution Control & Ecology Commission (APC&EC) Rule 19, Chapter 9. If any of the sources evaluated in the proposed SIP were to submit a permit application to significantly increase their emissions, DEQ's approved PSD program would require an evaluation to demonstrate that the requested change would not have an adverse impact on visibility in any federal Class I area. This PSD permitting process includes notification to EPA, federal land managers, and the public of the proposed permitting decision.

No changes to the proposed SIP are necessary in response to this comment.

Comment 4:

Two commenters suggested that if a source is achieving or can achieve lower emission rates with existing measures, DEQ should analyze the lower rate as a potential control, and should also consider possible equipment upgrades as potential additional controls.

Response 4:

For emissions units included in DEQ's reasonable progress analysis, DEQ examined lower emission rates and possible equipment upgrades as potential controls where applicable. See Chapter V of the proposed SIP.

For Domtar Ashdown Mill, DEQ requested (and Domtar provided) information about potential upgrades to their existing venturi scrubbers and use of additional caustic in the existing venturi scrubbers. After consideration of the four reasonable progress factors, DEQ determined that these control strategies were not necessary to make reasonable progress during Planning Period II.

For Flint Creek, Independence, and White Bluff, the emission units are achieving lower emission rates with existing measures than required by the SIP based on installation of low NOx burners. The operators of these facilities installed low NOx burners as part of their compliance strategy for the Cross-State Air Pollution Rule (CSAPR), which is a federal implementation plan. The lower emission rates achieved are a result of the installed technology, which is an inseparable component of operations of the boilers at each of facilities. Therefore, adoption of emission limits based on these low NOx burners are not necessary to prevent future emission increases or for ensuring reasonable progress.

B. Cost-effectiveness Thresholds

Comment 5:

Two commenters suggested that DEQ reconsider its cost-effectiveness thresholds, which are based on the ninety-eighth percentile of costs, determined reasonable during Planning Period I. Both commenters contended that DEQ should have considered higher cost-effectiveness thresholds for Planning Period II.

One commenter pointed to cost-effectiveness thresholds used by other states for their second-round regional haze plans in the range of $4000 - $10000/ton. The commenter gave examples from the following states: Arizona ($4,000 to $6,500/ton), New Mexico ($7,000 per ton), Oregon ($10,000/ton), Washington ($6,300/ton for Kraft pulp and paper power boilers), and Colorado ($10,000/ton). The commenter also pointed to language regarding source selection in EPA's July 8, 2021 clarification memo to support their assertion that higher cost-effectiveness thresholds should be considered for Planning Period II.

Response 5:

DEQ maintains that the determination of cost-effectiveness thresholds for EGUs and non-EGU industrial sources is reasonable. DEQ fully justified that reasoning in the proposed SIP. See Chapter V, pages V-13 through V-15. The 98th percentile metric DEQ chose (which was based on Planning Period I costs, escalated to 2019 dollars) ensures that costs incurred multiple times by sources of a similar type are captured while potential outliers that may have only occurred once or twice are eliminated, as suggested by EPA guidance.[2]

DEQ disagrees with the assertion that cost-effectiveness metrics must necessarily increase with each planning period. The iterative nature of Regional Haze planning allows states to consider the retirement and replacement of older industrial facilities by cleaner, more efficient facilities. In addition, the iterative planning process enables states to take advantage of further innovations that drive down emissions of visibility impairing pollutants, lower the cost of control technologies, or create new control technologies that enable facilities to achieve even lower emission rates. See 64 FR 35714 at 35732.

There is no set cost-effectiveness threshold for this program in the Clean Air Act or in the Regional Haze Rule. States are given discretion to determine these thresholds for in-state sources independently of other states, and as EPA planning period II guidance states, "A state may find it useful to develop thresholds for single metrics to organize and guide its decision-making. As the Ninth Circuit explained in NPCA v. EPA, 788 F.3d at 1142, the Regional Haze Rule does not prevent states from implementing "bright line" rules, such as thresholds, when considering costs and visibility benefits. However, the state must explain the basis for any thresholds or other rules (see 40 CFR 51.308(f)(2))." [3]

DEQ notes that some of the states pointed to by the commenter are considering additional factors, including additional cost metrics, other statutory factors, and visibility modeling. DEQ notes that all of the states cited to by the commenter are in the western United States, which has many more Class I areas including Class I areas that are not on track to make reasonable progress by 2028 in comparison to the glidepath for achieving natural visibility conditions by 2064.[4] All of the Class I areas that are reasonably anticipated to be impacted by Arkansas

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[2] EPA guidance states that "when the cost/ton of a possible measure is within the range of the cost/ton values that have been incurred multiple times by sources of similar type to meet regional haze requirements or any other [Clean Air Act] requirement, this weighs in favor of concluding that the cost of compliance is not an obstacle to the measure being considered necessary to make reasonable progress." EPA's 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period

[3] https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf

[4] The state RH SIPs that the commenter cites to justify higher cost-effectiveness thresholds in Arkansas are not representative of Arkansas's standpoint, either in the number of federal Class I areas affected or the progress toward visibility goals of 2064 at those areas. Arizona (AZ) is home to twelve federal Class I areas; one in-state federal Class I area is currently tracking above the URP "glidepath," and after proposed controls in the AZ SIP, the same areas is projected to be above the glidepath in 2028. AZ did not consider visibility as a "5th factor" but did use URP to further support that no additional controls are necessary for PPII for NOx.

Colorado (CO) is home to thirteen federal Class I areas; all federal Class I areas in CO are below the URP and expected to remain so after controls in the proposed RH SIP. Colorado has a 5% nitrate plus sulfate impact on two out of state areas, that are on-track and expected to remain so through 2028. Notably, Colorado notes several coal-EGU retirements through 2029 that are driving the majority of their RPG progress for planning period II; predominantly, four-factor analyses performed resulted in determinations by CO that existing permit limitations or sources are on track to make greater progress than the glidepath *before* consideration of the controls that DEQ and other states in the central United States region have included in their long-term strategies. While the glidepath is not a safe harbor, the Regional Haze Rule explicitly requires states to perform additional demonstrations and consider additional controls if the Class I areas impacted by their state are projected to be above the glidepath for the Planning Period. DEQ maintains that the proposed SIP provides adequate justification, is consistent with EPA's 2019 Guidance for Second Planning Period Regional Haze SIPs, and is approvable with the selected cost-effectiveness thresholds.

No changes to the proposed SIP are necessary in response to this comment.

Comment 6:

Two commenters questioned DEQ's application of different thresholds for different source types. One commenter requested additional justification for the use of different thresholds. One commenter argued that the proposed SIP's discussion of differences in how costs impact electric generating units (EGUs) as compared to industrial facilities is inappropriate because it "implicitly considers affordability, which is not one of the four statutory factors." The commenter points out that the Clean Air Act and Regional Haze Rule do not make a distinction concerning how the four factors should be applied to different sectors.

Response 6:

DEQ's use of different thresholds for different source types to evaluate cost of compliance is reasonable and consistent with EPA guidance, which states that "when the cost/ton of a possible measure is within the range of the cost/ton values that **have been incurred multiple times by sources of similar type** to meet regional haze requirements or any other CAA requirement, this weighs in favor of concluding that the cost of compliance is not an obstacle to the measure being considered necessary to make reasonable progress." These commenters imply that states cannot rely on EPA guidance in making considerations for what control strategies are appropriate for the purposes of SIPs. Regardless of this implication, DEQ did include additional discussion, beyond pointing to EPA's guidance, about differences between EGUs and other source categories. See Chapter V, pages V-13 through V-15 of the proposed SIP.

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control operating parameters were sufficient for RPGs, and few new controls were proposed to be adopted for planning period II.
Oregon (OR) is home to twelve federal Class I areas; three in-state federal Class I areas are currently tracking above the URP "glidepath," and two out of state areas are just above or right at the URP. After proposed controls in the OR SIP, the same five areas are projected to be above the glidepath in 2028.
Washington is home to eight federal Class I areas; two in-state federal Class I areas are currently tracking above the URP "glidepath," but are projected to be back on track in 2028 after proposed controls are phased in.

DEQ disagrees with the commenter who implies that states cannot consider factors beyond the four statutory factors. The commenters assertion is contrary to EPA's guidance for the Second Planning Period, which states that "neither the [Clean Air Act] nor the [Regional Haze] Rule suggest that only the listed factors may be considered" and provides guidance to states on how they can consider visibility benefits as an additional factor.[5] DEQ's discussion of how costs are borne differently by different sectors was illustrative of why different thresholds are appropriate for different source types.

C. Interest Rate Assumptions

Comment 7:

Two commenters recommended that DEQ reconsider using a bank prime rate of 3.25% (as of the date of the initial SIP analyses), and instead use a 7% interest rate which was more consistent with the industry standard of 10.5%. The commenters point out that a 7% interest rate is still a conservative figure. However, 7% better reflects "the real costs expected to be imposed on select sources" than the bank prime rate used in the proposed SIP.

Response 7:

In light of recent rate hikes to the bank prime rate, DEQ agrees with the commenters on this point. In addition, the Planning Period I cost data that DEQ used to develop its cost thresholds were based on a 7% interest rate. Therefore, using a 7% interest rate in determining cost of compliance for control strategies in Planning Period II provides for an apples-to-apples comparison of anticipated costs to DEQ's cost thresholds. In addition, DEQ has observed that EPA has used a 7% interest rate assumption in multiple proposed rulemakings since the public notice of the Proposed SIP, including EPA's proposed new source performance standards and emission guidelines for the oil and natural gas sector and EPA's proposed federal implementation plan to address interstate transport for the 2015 ozone national ambient air quality standard.

In response to these comments, DEQ has revised the interest rate assumptions for its cost of compliance analyses in the proposed SIP.

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[5] https://www.epa.gov/sites/default/files/2019-08/documents/8-20-2019_-_regional_haze_guidance_final_guidance.pdf p. 36

D. Comments about Specific Facilities

1. Entergy White Bluff

Comment 8:

One commenter suggested that for Entergy White Bluff, DEQ should evaluate SO_2 controls and cost-effectiveness during the interim between EPA approval of the Regional Haze Planning Period II SIP and the cessation of coal combustion on or before December 31, 2028. One commenter supported DEQ's conclusion that White Bluff did not need to undertake a four-factor analysis for Planning Period II.

Response 8:

Due to the short remaining life of Entergy-White Bluff, there are no new SO_2 controls or other interim controls that would be reasonable based on the consideration of the four factors. DEQ performed a recent analysis of controls that could be implemented in the interim before the cessation of coal combustion for the Arkansas Planning Period I Phase II SIP revision.[6] Under the remaining useful life and higher emission assumptions used in that analysis, none of the technically feasible control technologies would be cost-effective based on DEQ's cost-effectiveness thresholds for the proposed SIP. Based on the even shorter remaining useful life and lower emissions from White Bluff as a result of switching to lower sulfur coal and installing low NOx burners, the costs in dollars per ton of these technologies would be even greater. Furthermore, the decision not to perform a four-factor analysis for a source expected to close by December 31, 2028 is supported by EPA guidance.[7]

No changes to the proposed SIP are necessary in response to this comment.

2. FutureFuel Chemical Company (FutureFuel)

Comment 9:

One commenter requested further explanation to support the statement that low NOx burners are not a technically feasible control technology for Future Fuel's coal-fired boilers. The commenter pointed to a citation in the proposed SIP regarding SNCR and SCR applicability at the unit.

Response 9:

DEQ performed a review of the EPA RACT/BACT/LAER database to verify that low NOx boilers have not been implemented for similar equipment as part of new source review. There

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[6] See pages 21 – 26 of the Phase II Regional Haze SIP for Planning Period I. www.adeq.state.ar.us/ar/planning/sip/pdfs/regional-haze/rh-phase-ii-sip-narrative-final.pdf

[7] See page 20 of EPA's August 2019 Guidance on Regional Haze State Implementation Plans for the Second Planning Period. 8-20-2019_-_regional_haze_guidance_final_guidance.pdf (epa.gov)

were three entries for spreader-stoker boilers in the RBLC database: IA-0013, IA-0015, and MI-0005. None of these entries identified low NOx Burners as a RACT, BACT, or LAER control strategy. In addition, low NOx burners are not listed as an available control strategy for industrial coal-fired stoker boilers in EPA's Menu of Control Measures.

DEQ will revise the citation included in the proposed SIP to include this explanation to support the statement that low NOx burners are not a technically feasible control technology for FutureFuel's three coal-fired boilers.

Comment 10:

One commenter disagreed with the rationale in the proposed SIP for selecting 2% sulfur content coal instead of 1.5% sulfur content coal for FutureFuel's three coal-fired boilers given that both fuel switching strategies were determined cost-effective. The commenter stated that using the same threshold for incremental cost-effectiveness as was used for average cost-effectiveness is not a reasonable argument for dismissing 1.5% sulfur coal. Another commenter suggested that the decision to select a 2% sulfur content coal instead of 1.5% sulfur content coal is arbitrary because both strategies are cost-effective.

Response 10:

After consideration of the public comments received, DEQ consulted with FutureFuel representatives and EPA Region 6 about the control strategy for FutureFuel regarding the reasonableness and availability of 1.5% sulfur content coal. In response to these comments, DEQ is revising its Planning Period II control strategy selection for FutureFuel based on implementation of a 1.5% sulfur content strategy. DEQ will revise the proposed SIP narrative, related appendices, and administrative order to reflect this change in strategy.

Comment 11:

One commenter suggested that for FutureFuel, DEQ should provide additional discussion on how the application of DEQ's cost-thresholds is reasonable for FutureFuel considering that the estimated cost of dry scrubbers (SDA) in the proposed SIP is not much higher than DEQ's threshold.

Response 11:

After consideration of the comments received on the proposed SIP, DEQ continues to find that the cost of compliance with an emission limit based on SDA is not reasonable for FutureFuel's coal-fired boilers for Planning Period II. DEQ contends that the cost-effectiveness threshold determined for non-EGU boilers, including FutureFuel's boilers, is reasonable and well-justified. See Response 6. By definition, a threshold is a policy tool used to create a bright-line between two choices. Therefore, "not much higher" than a threshold is not a reasonable argument for changing policy decisions. Furthermore, DEQ has revised its interest rate assumptions for the purposes of calculating cost of compliance in response to comments, which has increased the cost per ton metric for all control strategies that require a capital investment. See Response 7 for consideration of interest rates and DEQ's rationale for revising interest rate assumptions for cost of compliance determinations. See Chapter V of the final SIP for revised cost per ton values associated with each control strategy. Due to the shifting economic landscape of 2020-2022, and increasing interest rates, initial capital, operation, and maintenance (O&M) cost estimates prepared in 2019 for SDA purchase and installation have likely increased since this analysis was performed. Time constraints preclude DEQ from requesting updates to capital and O&M costs that account for these changes. Nevertheless, any updates would drive up the cost of compliance for this technology and DEQ has already determined that the technology is not cost-effective for FutureFuel for Planning Period II based on the 2019 cost data.

Comment 12:

One commenter pointed out that for FutureFuel, two figures—3.9 lb/mmBtu and 3.7 lb/mmBtu — were used in emissions and cost-effectiveness calculations, and asked for an explanation.

Response 12:

DEQ recognizes this inconsistency. DEQ reviewed the information provided by FutureFuel and determined that the emission rate associated with switching to 2% sulfur coal at FutureFuel is 3.69 lb/mmBtu. See DEQ's revised cost calculations for FutureFuel. DEQ will make the appropriate changes to the SIP and supporting documentation to correct this error.

Comment 13:

For FutureFuel, one commenter requested that DEQ explain why the SO_2 emission limit is being considered across all three boilers rather than individual limits for each boiler.

Response 13:

FutureFuel's coal-fired boilers operate as a single emission unit, i.e., the boilers share a common primary fuel conveying system, a common ash handling system, and a common 200-foot-tall stack. These three boilers are the source of 99% of the facility's SO_2 emissions. See Chapter V, beginning on page V-25. Within the Title V permit for the facility, these three boilers are permitted as one unit with a combined emission limit because they function as one unit. DEQ analyzed the three boilers as a single source of SO_2 emissions, as the individual unit emissions are co-mingled in the single exiting stack.

Comment 14:

One commenter suggested that DEQ did not request adequate documentation for FutureFuel's off-site liquid waste disposal cost. The commenter suggests that FutureFuel could burn these wastes in natural gas-fired industrial boilers. Therefore, the commenter asserts that these costs should be removed from the cost-effectiveness calculations for the fuel switching to natural gas scenarios. As a result of zeroing out these costs, the commenter asserts that the cost-effectiveness for fuel-switching the three coal-fired units to natural gas is $436/ton.

Response 14:

DEQ requested additional information from FutureFuel about why FutureFuel could not specify that the replacement natural gas boilers have the capability to burn the wastes, revise the costs for switching natural gas control strategy to specify for such boilers, or delete the offsite liquid waste disposal cost from the calculations.

FutureFuel explained that the facility is a batch chemical facility producing a wide array of chemical intermediates and consumer products. Gas-liquid boilers, as proposed by the commenter, generally require a consistent feed composition to reliably produce steam. The liquid streams captured for energy recovery in the boilers at FutureFuel constantly vary in composition, density, and energy content. Also, streams co-fired with coal to generate steam typically contain salts and other matter that manifest as solid deposits within the boiler system. The stoker boiler design used at FutureFuel is well suited to handle the varied liquid streams generated at the facility and safely dispose of the solids that precipitate along with the ash while meeting all Maximum Achievable Control Technology (MACT) standards per 40 CFR 63, Subpart EEE. FutureFuel is not aware of any MACT EEE compliant gas-fired industrial boilers located at batch chemical facilities that co-burn highly variable streams to produce plant steam.

DEQ finds FutureFuel's explanation regarding why the offsite waste disposal is necessary for the two scenarios in which FutureFuel would retrofit or replace all three boilers with natural gas to be reasonable. Documentation for FutureFuel's waste disposal cost estimates have been added to Appendix G.

Comment 15:

One commenter asserted that FutureFuel used the wrong cost model for estimating wet scrubber costs and because the wrong model was used, the public is precluded from independently using EPA's cost model to estimate costs.

Response 15:

DEQ disagrees with the commenter's assertion that the public was not provided adequate information to review during the public comment period. As noted in the proposed SIP and the FutureFuel cost calculation spreadsheet, DEQ made the corrections necessary for the cost estimate for wet scrubbers to ensure consistency with the EPA Control Cost Manual.

No changes to the proposed SIP are necessary in response to this comment.

Comment 16:

One commenter stated that FutureFuel should have evaluated a single SO_2 emission control system for all three coal-fired boilers given that they share a common primary conveying system, ash handling system and stack. The commenter asserts that the assumption of installing one post-combustion control instead of two would result in cost-savings.

Response 16:

In discussions with FutureFuel, they explained that pollution control devices must be on-line whenever boilers are operating. Understandably, this is necessary to be a good environmental steward and to comply with environmental regulations. This is especially critical when production or steam generating units cannot be quickly shut down to mitigate emissions. For example, FutureFuel maintains and operates two parallel Regenerative Thermal Oxidizers (RTOs), two parallel Thermal Oxidizers (TOs), and Electrostatic Precipitators (ESPs) on each of the three coal boilers to improve the ability to comply with environmental regulations at all times, even if one unit should experience a mechanical failure. There are many examples at FutureFuel (and throughout industry) where this strategy is practiced to maintain compliance with environmental regulations and to facilitate robust operation and maintenance of equipment. Parallel systems for the coal-fired boilers are necessary, because these boilers cannot be quickly taken off-line without damaging the boilers and causing significant safety and environmental hazards throughout the facility. Abrupt loss of a single coal-fired steam boiler can and has caused on-site shutdowns due to reduced steam supply. The loss of all three coal-fired boilers at once due to failure of a single emission control device would cause a site shutdown.

The consequences of steam loss can vary widely, but no chemical processes at FutureFuel can continue to operate without steam. A few of the many consequences of an abrupt steam loss include:

1. Solidification of raw materials and products in tanks, instruments, and process units will cause equipment damage, leaks and spills, safety concerns, and off-quality material that must be discarded.

2. Agitator, pump, and fan failures will compromise safety, environmental, and process control systems. For example, some emergency cooling equipment have circulation pumps driven by steam.

3. Vacuum (steam jet) systems that control vessel pressure, material transfer systems, and distillation column pressures can cause unsafe reaction conditions, loss of control in distillation columns, and multiple other process failures. Loss of vacuum control in some distillation columns can cause a 2-week outage and create off-quality material that must be discarded.

The rationale for redundant systems applies to absorbers, packed towers, wet scrubbers, DSI, and many other emissions control systems.

Based on FutureFuel's rationale, DEQ find that the equipment specifications provided by FutureFuel for post-combustion controls is reasonable.

No changes to the proposed SIP are necessary in response to this comment.

Comment 17:

One commenter asserts that the efficiency assumptions for the purposes of the four-factor analysis for FutureFuel's three coal-fired boilers should be 98% for wet scrubbing and 95% for dry scrubbing.

Response 17:

DEQ's analysis of EPA's Menu of Control Measures indicate variable performance for wet scrubbing in the range of 90 – 99% and in the range of 90 – 95% for dry scrubbing systems for coal-fired boilers. After discussion with FutureFuel, DEQ has revised its cost calculations based on the commenter's suggestion because FutureFuel had no site-specific engineering analysis to justify why the higher end of the control performance range suggested by the commenters is not reasonable.

Comment 18:

One commenter asserted that an explanation of why demolition of an existing control room was necessary for the installation of certain controls and documentation of the cost estimate of $1,000,000. The commenter further requested explanation and documentation for assumed costs associated with a pipeline from a wet scrubber to the wastewater treatment plant. The commenter requested documentation to support the conclusion that a sulfuric acid tank and line for wet scrubber installation is necessary.

Response 18:

DEQ consulted with FutureFuel for further explanation in response to this comment.

FutureFuel explained that the facility's boilers are in a congested area. A control room near the boiler stack must be removed to install an SO_2 emission control system. This location, near the boiler exhaust ducts, is desired so that minimal ductwork (and therefore minimal pressure drop) will be added to the boiler exhaust system. FutureFuel boilers operate at negative pressure and any increased pressure drop caused by SO_2 control systems and associated ductwork will require the boiler induced draft system to be rebalanced. Minimizing the distance from the boiler to the SO_2 control system will reduce the likelihood that new induced draft boiler fans will be required. The full impact and associated re-engineering cannot be fully determined until an extensive design evaluation is completed. However, a more remote location for SO_2 control increases the likelihood that the boiler draft system will require a more extensive redesign and increase the cost estimate for installing SO_2 emission controls beyond the $1,000,000 required to demolition the control room.

The control room described for demolition is a stand-alone heavy steel framed building. Conduit, wiring, HVAC, the building itself (approximately 40 ft. by 30 ft.), plumbing, and the concrete foundation must be removed to prepare the site for any proposed emission control devices and associated peripheral equipment (i.e. pumps, tanks, emergency protection equipment, etc.). In addition, there is an environmental control lab in the building that must be relocated. Furthermore, and perhaps most importantly, the building houses electric panels, instrument termination cabinets, control panels, and a computer system associated with an existing liquid incinerator. A recent estimate received by FutureFuel for removing and relocating the electrical and control equipment in this building was almost $1.2 million dollars. FutureFuel asserts that the estimated demolition cost provided in the initial analysis actually falls short of the actual cost.

Wet scrubber systems generate waste (in this case it could be a slurry), which must be collected for disposal off-site or routed to an on-site treatment system. The proposed pipeline estimated in the initial response assumed on-site neutralization, and disposal of the liquid phase was the least costly disposal option. Disposal of the solids phase was not included in the initial cost estimate because the quantity of solid material in the stream was unknown. The cost estimate was based on a pipeline from the control system to a wastewater treatment tie-in. A pH adjustment system was included in the design to ensure the discharge is within permitted limits. Waste from the emission control device is otherwise assumed to be suitable for the existing wastewater system. Corrosion resistant piping is required due to the nature of this stream. This piping is expected to be at least $300 per foot installed, but it could be higher if a larger pipe diameter is needed. The distance from the emission control devices to the wastewater connection location is in excess of 1200 feet. The estimate does not include pipe stands needed to elevate the pipe overhead, allowing continued equipment access to the area. A pump-driven recirculation system may be required to keep the waste slurry from plugging. Therefore, the length of pipe to the discharge point may need to be doubled, but this is not included in the estimate. The cost for the waste slurry piping alone will exceed $360,000. The neutralization piping is local and lower cost per foot (approx. $21,000 installed). A feed tank ($50,000), multiple pumps ($60,000 for three intrinsically safe pumps), wiring and controls for the pumps ($20,000), and intrinsically safe instrumentation ($30,000) are needed to ensure adequate neutralization of the waste and safe operation of the waste disposal system. A 600-foot underground drain line to wastewater treatment from the emission control device pad is also required ($165,000). All of the above-ground piping transporting the waste slurry will require tracing and insulation to prevent freezing in the winter months ($48,000). Filtering and temperature control of the DSI waste stream was not included in the cost estimate but may significantly increase the capital and operating costs.

The costs described above make the original $700,000 for the waste discharge system from the emission control devices a very conservative estimate.

	#	$	total
slurry pipe	1200	$ 300	$ 360,000
pipe rack	1200	$ -	$ -
solid collection and disposal	1	$ -	$ -
slurry recirculation system	1	$ -	$ -
neutralization pipe	600	$ 35	$ 21,000
tank & instruments	1	$ 50,000	$ 50,000
pumps	3	$ 20,000	$ 60,000
control instruments	1	$ 30,000	$ 30,000
pad drain line	600	$ 275	$ 165,000
trace & insulate	1200	$ 40	$ 48,000
			$ 734,000
Contingency	30%		$ 220,200
Total			$ 954,200

There are no available tanks in the vicinity of the location for the proposed wet emission control devices that are designed to provide sodium hydroxide. Tanks must be installed along with pumps, piping, and instrumentation from unloading stations to the tank and from the tanks to the emission control devices. Dilution of the sodium hydroxide solution to a concentration is needed to minimize salt precipitation. Concentrated sodium hydroxide is more economical than 15% to 20%, which is expected to be the preferred concentration range to minimize fouling. The dilution systems will be designed to provide the desired concentration. A heat removal system will also be needed to control the exothermic reaction. Sodium hydroxide lines plug over time from salt formation, so a recirculation system is needed to feed the proposed wet scrubber system. Design reviews of pH adjustment systems show a larger tank as a supply tank into which trucks and railcars can off-load sodium hydroxide while a second smaller tank is employed to feed each emission control device. This configuration is needed to facilitate good operational control while providing adequate capacity in the event sodium hydroxide supply is irregular. The design includes one large sodium hydroxide storage tank feeding small process tanks (one for each control device). Outdoor equipment containing sodium hydroxide requires heat tracing and very effective insulation to prevent freezing in the winter. The cost for this system was derived from discussion with an equipment vendor and was included as part of the overall cost estimate.

No changes to the proposed SIP are necessary in response to this comment.

Comment 19:

One commenter suggested that FutureFuel’s claims that an extended outage and related costs is not adequately documented.

Response 19:

In response to this comment, DEQ requested additional information from FutureFuel.

FutureFuel explained that the three boilers generate high pressure and high temperature steam that is distributed through a common header feeding the entire facility. The exhaust from the combined unit is very hot, and the boilers must be off-line to safely work on the ductwork. The existing ductwork in the area where the pollution control equipment would be installed also contains asbestos. Asbestos abatement contractors would be required to remove and dispose of all asbestos containing material. This work would extend the duration of the boiler downtime. Cool-down of the boilers alone is expected to take days. Online references consulted by FutureFuel (Babcock & Wilcox) state that several weeks would be required for the tie-ins. Construction will also be slowed, because the area is congested and rental crane(s) and man-baskets will have to work from multiple positions to make the tie-ins and complete insulation work.

FutureFuel does not have surplus steam generation capacity, and supplemental capacity will be required to meet customer obligations. The process of connecting a rental boiler will take less time than the ductwork modifications needed for pollution control device construction activity. A rental boiler will provide FutureFuel the ability to run processes and meet customer obligations while pollution control equipment is being installed, and it will also provide some protection against unforeseen construction delays.

Taking coal-fired boilers off-line would eliminate FutureFuel's ability to treat some waste fuel streams on-site. With limited ability to store waste, production waste must be shipped off-site for disposal. The quantity of material to be disposed of off-site is based on historical records.

No changes to the proposed SIP are necessary in response to this comment.

Comment 20:

One commenter asserts that a default value of 10% of the direct and indirect costs is typically used for CF [contingency factor], but concedes that "values of between 5% and 15% may be used" based on EPA's Control Cost Manual.

Response 20:

The 7th Edition of the EPA Cost Control Manual became final in 2021. FutureFuel submitted these cost estimates in April 2020. The EPA/452/B-02-001 EPA Air Pollution Cost Control Module (Sixth Edition of January 2002), as well as the 7th Edition, discusses contingency factors Section 1, Chapter 2.2. The manual provides guidance on the accuracy of cost estimates at different phases of a project. They describe a Study Phase, Scope Phase, Project Control Phase, and a Detailed Phase. Guidance is provided on the cost accuracy of each phase and is shown in Figure 2.1.

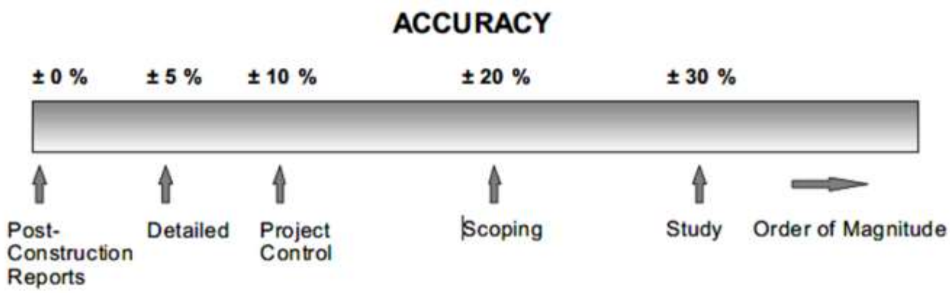


Figure 2.1: The Continuum of Accuracy for Cost Analyses

FutureFuel firmly believes at this stage of this process that during the Study Phase, a 30% contingency is appropriate and in agreement with EPA guidance. As noted in the proposed SIP, DEQ finds that a 20% contingency is a more conservative estimate and consistent with EPA guidance. The application of evaluated technology to boilers similar to FutureFuel's is limited and the values used by FutureFuel for capital costs are based on cost estimation tools rather than vendor-supplied estimates. Therefore, DEQ concludes the estimated cost using EPA tools is most reasonably characterized as "scoping," which EPA guidance indicates has a 20% accuracy.

No changes to the proposed SIP are necessary in response to this comment.

Comment 21:

One commenter asserted that FutureFuel's outlet sulfur rate should be higher than calculated by FutureFuel.

Response 21:

FutureFuel performs sampling and content analysis for all fuels that enter their three coal-fired boilers using EPA-approved methods to demonstrate compliance with multiple permit conditions. The discussion put forth by the commenter does not convince DEQ that FutureFuel's data is unreliable. DEQ is unaware of any enforcement action against FutureFuel for incorrect calculation of fuel sulfur and heat content.

No changes to the proposed SIP are necessary in response to this comment.

Comment 22:

The commenter asserts that more information is necessary related to CEMS (continuous emissions monitoring) for SO2 and NOx.

Response 22:

The only CEMS on the 6M01-01 coal-fired boilers are related to CO, O2, and THC. All other Title V Permit conditions are maintained by the continuous monitoring system (CMS). These CMS controls are based on the performance of the CFBs during multiple test conditions.

No changes to the proposed SIP are necessary in response to this comment.

Comment 23:

The commenter asserts that 1% sulfur content coal was once used (pre-1982) at the facility to fuel the boilers at the facility, when it was still Eastman. A permit amendment July 23, 1982 authorized the increase of sulfur content to 4%. If the original 1% sulfur coal limit applied to all coal-fired boilers at the Eastman facility at that time, the commenter contends that the boilers currently in operation were originally limited to using 1% sulfur coal, and could return to this limit.

Response 23:

FutureFuel's boilers are the same as those in operation pre-1982, but FutureFuel explains that the coal market has changed dramatically since 1982. FutureFuel worked with a national coal broker to evaluate coal sources marketing coal with less than 1.5% sulfur content. The broker was unable to find sources meeting stoker-grade specifications.

Stoker-grade coal specifications are shown in the table below for reference:

Coal Specifications

Parameter	Value	UoM
Maximum Coal Size	≤ 2 x 0	inch
Preparation Method	Washed	-----
Maximum Fines (1/4 inch, %)	< 40-50%	%
Maximum Ash	≤ 10	%
Maximum Sulfur	≤ 1.5	%
Minimum Heating Value	10,000	Btu/lb
Minimum Fusion Temp	Oxidizing	-----
Initial Deformation	≥ 2100	deg F
Softening	≥ 2330	deg F
Fluid	≥ 2550	deg F

In addition to the specified stoker-boiler coal parameters shown in the table above, coal must meet FutureFuel permitted hazardous constituent parameter specifications. It must also be obtainable in a lot size that can be managed at the facility, with transportation and demurrage fees that meet reasonable cost-per-ton parameters.

No changes to the proposed SIP are necessary in response to this comment.

Comment 24:

One commenter asserts that the 80% efficiency used to calculate the cost-effectiveness of SCR must be verified and that an explanation was needed as to why 40% efficiency was used for SNCR calculations.

Response 24:

80% is the control efficiency listed for SCR and 40% is the control efficiency listed for SNCR in EPA's Menu of Control Measures for Industrial Coal Stoker Boilers.

No changes to the proposed SIP are necessary in response to this comment.

Comment 25:

One commenter asserts that DEQ should have used a 30-year assumption for SNCR systems in the four-factor analysis for FutureFuel.

Response 25:

The commenter's contention that DEQ should have used a thirty-year amortization rate rather than a twenty-year amortization rate is inappropriate. EPA's control cost manual estimates SNCR life between 15 and 25 years.[8] EPA uses twenty years as a reasonable lifetime assumption for their SNCR system cost analysis. Twenty years is the default assumption in EPA's cost calculation tool for SNCR. The use of twenty years as a reasonable assumption was confirmed with EPA during pre-proposal consultation.

Comment 26:

One commenter provided "corrected" SCR and SNCR cost-effectiveness calculations for FutureFuel.

Response 26:

DEQ disagrees with the commenter's "corrections." No changes are necessary in response to this comment.

3. Domtar Ashdown Mill (Domtar)

Comment 27:

One commenter suggested that DEQ include additional discussion on how the application of DEQ's cost-effectiveness thresholds is reasonable as it relates to the Domtar boilers evaluated in the four-factor analysis, considering that no new controls or improvements to existing controls

[8] Chapter 1 - Selective Noncatalytic Reduction (epa.gov) See page 1-54

were selected for any of the boilers and considering that increased reagent usage at the existing scrubbers for the No. 2 Power Boiler is estimated to cost $3,590/ton, which is only slightly higher than DEQ's selected cost threshold of $3,328/ton for industrial boilers.

Response 27:

After consideration of the comments received on the proposed SIP, DEQ continues to find that the Planning Period II determinations with respect to Domtar Ashdown Mill are reasonable. See Response 11 for discussion of the use of thresholds in policy determinations, changes to interest rate assumptions, and consideration of current economic conditions, which are also applicable to control strategies evaluated for Domtar Ashdown Mill.

No changes to the proposed SIP are necessary in response to this comment.

Comment 28:

One commenter stated that EPA recently took final action to approve SO_2 and NOx emission limits for the Domtar Ashdown Mill No. 2 Power Boiler in the Arkansas Regional Haze Phase III SIP Revision for the first planning period, and asserts that DEQ should consider these recently approved emission limits in establishing the SO_2 and NOx baselines for the No. 2 Power Boiler in the four-factor analysis for the second planning period, citing EPA's guidance on regional haze SIP development for the second planning period: "Enforceable requirements are one reasonable basis for projecting a change in operating parameters and thus emissions" when selecting the baseline for the four-factor analysis.

Response 28:

DEQ requested actual emissions from selected sources for the purposes of conducting four-factor analyses. The actual emissions for No. 2 Power Boiler included in the four-factor analysis is consistent with the emission rates EPA approved for the first planning period. As part of the Phase III Regional Haze Planning Period I SIP submittal, DEQ included documentation from Domtar that Ashdown Mill has been complying with the alternative-to-BART emission limits since December 2016. Therefore, Domtar was in compliance with the EPA-approved emission limits during the entire period used to establish the SO_2 and NOx baselines for No. 2 Power Boiler for the Planning Period II four-factor analysis.[9]

No changes to the proposed SIP are necessary in response to this comment.

[9] See DEQ's Phase III Regional Haze SIP for Planning Period I for the referenced documentation. https://www.adeq.state.ar.us/air/planning/sip/pdfs/regional-haze/final-phase-III-sip-combined-files.pdf

Comment 29:

Domtar commented that it had recently submitted a permit modification application to DEQ including cessation of coal use for No. 2 Power Boiler.

Response 29:

DEQ acknowledges Domtar’s planned changes at Ashdown Mill. In response to this comment, DEQ had a conversation with Domtar about whether the planned changes will result in further emission reductions. Domtar indicated that it will continue to burn other fuels allowed under the Ashdown Mill permit in addition to natural gas. However, Domtar has not requested changes to its permitted emission limits for SO_2 or NOx in this permit revision application.

No changes to the proposed SIP are necessary in response to this comment.

Comment 30:

Domtar commented that it objects to the consideration of SNCR for Domtar Ashdown Mill Power Boilers as having a 27.5% control efficiency (Scenario 2), and point to source-specific documentation that only 3% overall control efficiency is expected at the Ashdown Mill.

Response 30:

DEQ appreciates the comment, and has included both Scenarios in the SIP proposal to bolster the analysis by comparison; conclusions drawn from either Scenario are the same, that SNCR is not an effective or appropriate control for Power Boiler No. 2 or Power Boiler No. 3.

No changes to the proposed SIP are necessary in response to this comment.

Comment 31:

Domtar commented that emission rate values in Table V-17 were incorrect and provided the correct values included in their four-factor documentation. Domtar also requested that DEQ update the cost-effectiveness values for SO2 controls in the SIP to reflect the corrections to the emission rates and capital recovery interest rate.

Response 31:

DEQ acknowledges this error and will revise the values as presented in Domtar’s revised (August 14, 2020) Response to January 8, 2020 Regional Haze Four-Factor Analysis Information Collection Request (page 2-4, Table 2-4). The values will be revised in Chapter 5 Table V-17, to 279.8 tpy and 579.1 tpy, respectively.

DEQ agrees that the 7% is a more appropriate interest rate for estimating capital recovery in this context and that the cost-effectiveness calculations should be updated to reflect the correct emission rates. See Response 7 for more detail on DEQ's consideration of interest rates. DEQ will update the cost-effectiveness values in the SIP.

Comment 32:

One commenter recommended including No. 2 Lime Kiln and No. 3 Lime Kiln for Domtar in four factor analysis as significant sources of NOx.

Response 32:

DEQ disagrees that the proposed units are significant sources of NOx. The annual emissions from these units range from one ton per year of NOx to 164 tons per year of NOx based on the data provided by the commenter. DEQ examined emissions associated with each emission unit at each source selected for a four factor analysis to determine which units actually emitted 250 tons per year or more in any recent year of NOx or SO2. This exercise was intended to limit four factor analyses to emission units with the potential to meaningfully reducing contributions from Arkansas sources to visibility impairment at Class I areas.

No changes to the proposed SIP are necessary in response to this comment.

Comment 33:

One commenter reviews EPA and DEQ actions related to Regional Haze planning period I BART determinations for Domtar Power Boiler No. 1 and Power Boiler No. 2.

Response 33:

This comment pertains to final actions by EPA related to the EPA's Planning Period I federal implementation plan and DEQ's Phase III Regional Haze SIP for the first planning period of the Regional Haze program. The comment does not address any assumptions or requirements included in the proposed SIP.

No changes to the proposed SIP are necessary in response to this comment.

Comment 34:

One commenter recommends that DEQ review No. 2 power boiler calculations and that Domtar should produce documentation that the existing scrubber cannot be upgraded. Additionally, Domtar provided DEQ with a study completed by Lundberg in 2014; the document examines the addition of a new scrubber system downstream of the existing scrubber, but the document was provided to support the assumption that upgrades to the existing scrubber for the No. 2 Power Boiler would result in unquantifiable/insignificant improvements in emissions. The commenter asserts that Domtar should provide the correct Lundberg study that examined the upgrades to existing scrubbers, or explain how the 2014 "additional scrubber" study is applicable/supports this assumption.

Response 34:

DEQ requested that Domtar provide additional information in response to this comment. Domtar asserts that they can offer only their best engineering judgment based on the design of the scrubber, which was described in an “August 29, 2014, Supplemental Response” letter to EPA, which is included as Attachment A. A long-term study would be needed to determine the sustainability of EPA’s proposal, which cannot feasibly be performed on such a tight timeline as would be required to submit a timely SIP to EPA. Other previously submitted, pertinent documentation was also provided in response to this comment, Attachment B, “Response to U.S. EPA Information Request,” and Attachment C, “Domtar Comments on Arkansas BART FIP.”

With regards to the Lundberg study in question, in June 2012, Lundberg considered both options and decided that the new scrubber option was far superior to any potential upgrades to the existing scrubber, for which no quantifiable SO_2 reduction was possible. As such, the same Lundberg report is pertinent to Domtar’s conclusions for both options. See Attachment D, “Final _2 WESP Proposal…”

Comment 35:

One commenter recommends that DEQ revisit Domtar scrubber efficiency calculations at power boiler No. 2, asserting that scrubber efficiency figures and operation and maintenance (O&M) costs Domtar used are based on outdated data. The data in question comes from EPA’s 2016 TSD which was based on monthly average data from 2011-2013, and calculations were based on generic emission factors, not actual measured values of the amount of sulfur in each type of fuel.

Response 35:

DEQ requested additional information from Domtar in response to this comment. Domtar stated that recent and current market and supply chain issues have forced the mill to reduce its production rates, and more current data may not be representative of future operations and is certainly not representative of the capability of the mill. The 2011-2013 data is reasonably representative of typical operations. Also, site-specific information, where available, was used in all calculations, and supplemented with industry-specific information.

No changes to the proposed SIP are necessary in response to this comment.

Comment 36:

One commenter suggested that DEQ request additional documentation for costs of reagent for Domtar. The commenter asserts that bleach plant EO filtrate and demineralizer anion rinse water are both waste byproducts from the processes at Domtar, and maintain that much of the reagent used is either a waste product of the facility or is already purchased in large quantities for used in making the facility’s products. The commenter suggests that Domtar’s cost for the additional reagent would be relatively low.

Response 36:

DEQ requested additional information from Domtar in response to this comment. Domtar clarified that they utilize the bleach plant EO filtrate and demineralizer anion rinse water to the extent that it is available. As pointed out in the comments, these are process *byproducts*, and only the amount that is created by the process can be used. Therefore, any additional emissions reductions must come through the purchase of additional caustic. Due to similar market and supply chain issues mentioned above, the price of caustic has increased. It is currently more than 50% higher than the value used by EPA.

No changes to the proposed SIP are necessary in response to this comment.

Comment 37:

One commenter recommends that DEQ require Domtar to consider low NOx burners for Power Boiler No. 2 and for Power Boiler No. 3; commenter believes the cost effectiveness for both units is reasonable.

Response 37:

DEQ requested additional information from Domtar in response to this comment. Domtar has explained why low NOx burners are not appropriate for No. 2 and No. 3 power boilers, quoting the National Council for Air and Stream Improvement: "Fuel NOx is the dominant NOx formation mechanism operative during wood combustion. However, common combustion modification techniques that suppress combustion air levels below the theoretical amount required for complete combustion have not been demonstrated to work for wood-fired boiler NOx control. Overfire air ports are claimed to lower NOx emissions from wood-fired stoker and fluidized bed combustion units (EPA 2001), although reports of such installations are lacking. Options for postcombustion (sic) controls include SCR and SNCR." (NCASI Handbook of Environmental Regulations and Control, Volume 1: Pulp and Paper Manufacturing, revised April 2013, page 10-13, emphasis added.)

When DEQ was researching possible controls for Domtar at the beginning of the RH SIP development process, there were no low NOx burners listed for Domtar's unit types in EPA's Menu of Control Measures, which further supports Domtar's assertion that this type of technology has not been demonstrated to be appropriate for wood-fired boiler NOx control.

No changes to the proposed SIP are necessary in response to this comment.

4. Flint Creek

Comment 38:

One commenter suggested DEQ should provide additional discussion on how the application of DEQ's cost-effectiveness thresholds is reasonable with respect to Flint Creek. The commenter noted that the cost per ton metric for SNCR at Flint Creek included in the proposed SIP ($5771/ton) is not much higher than DEQ's threshold for EGU boilers ($5086/ton). Another commenter suggested that DEQ should select SNCR at minimum as a reasonable progress control for Flint Creek.

Response 38:

After consideration of the comments received on the proposed SIP, DEQ continues to find that the Planning Period II determinations with respect to Flint Creek are reasonable. See Response 11 for discussion of the use of thresholds in policy determinations, changes to interest rate assumptions, and consideration of current economic conditions, which are also applicable to control strategies evaluated for Flint Creek.

No changes to the proposed SIP are necessary in response to this comment.

Comment 39:

One commenter alleges that DEQ's emission reduction assumption for implementation of SNCR at Flint Creek is too low and thinks the rationale behind DEQ's math for determining maximum versus average emission reductions potential of the control technology as applicable to Flint Creek is convoluted. The commenter provided a list of "Notable EGU SNCR Installation Monthly NOx" performance that they compiled to support their assertion that Flint Creek should be capable of achieving a monthly NOx limit of 0.14 lb/mmBtu or lower.

Response 39:

DEQ disagrees with the commenter. The commenter's suggested SNCR efficiency rate does not reflect facility-specific engineering analyses or typical SNCR-controlled NOx outlet rates for similar coal-fired EGUs. The SNCR system must be capable of handling the highest input rate anticipated from the exhaust system. However, the level of reductions anticipated would be based on average emissions. Therefore, DEQ used the maximum monthly NOx emission rate during the baseline (0.20 lb/mmBtu) to size the SNCR system. DEQ used the percent difference between the average monthly emission rate (0.186 lb/mmBtu) and the most stringent end of the vendor estimated SNCR outlet rate of 0.18 lb/mmBtu to calculate the anticipated control efficiency of the system.

The commenter's list of "Notable EGU SNCR Installation Monthly NOx Performance" is not representative of what Flint Creek should be able to achieve with installation of SNCR. First, the SNCR performance values used were provided by a vendor who performed facility-specific engineering analyses to calculate performance in the range of 0.18 - 0.20 lb/mmBtu. Second, the provided list cherry picks units capable of meeting the commenter's desired SNCR performance. While DEQ expects that the vendor who provided performance estimates for installation of SNCR at Flint Creek is likely to provide the best engineering analysis of what performance would be anticipated from a retrofit project at Flint Creek, DEQ pulled Air Markets Program Database data for SNCR monthly performance achieved by dry-bottom wall-fired boilers like Flint Creek between 2010 and 2021. SNCR performance at these units ranged from a minimum of 0.0 NOx lb/mmBtu to 1.5 lb NOx/mmBtu. The average NOx emission rates for dry-bottom wall-fired boilers with SNCR was 0.209 lb/mmBtu and the median NOx emission rate was 0.185 lb/mmBtu. See Attachment E (monthly-emissions-EGUs-SNCR). Based on this review, DEQ finds that the lower end of the vendor estimate for SNCR performance at Flint Creek is a highly aggressive basis for calculating anticipated emissions reductions from implementation of SNCR at Flint Creek.

No changes to the proposed SIP are necessary in response to this comment.

Comment 40:

One commenter alleges that DEQ's SNCR cost-effectiveness calculation for Flint Creek is overstated. They support this allegation based on their disagreements with DEQ's assumptions for equipment life, DEQ's assumptions for average emission reductions, DEQ's assumption that urea will be used for the SNCR, and DEQ's use of an older EPA SNCR spreadsheet for calculating SNCR cost-effectiveness. The commenter provides "corrected" values and concludes that the cost of SNCR at Flint Creek is $1,971/ton rather than $6,790/ton. The commenter asserts that, at minimum, DEQ should select SNCR as a reasonable progress control for Flint Creek.

Response 40:

The commenter's contention that DEQ should have used a thirty-year amortization rate rather than a twenty-year amortization rate is inappropriate. First, EPA's control cost manual estimates SNCR life between 15 and 25 years.[10] EPA uses twenty years as a reasonable lifetime assumption for their SNCR system cost analysis. Twenty years is the default assumption in EPA's cost calculation tool for SNCR. Second, SWEPCO's IRP indicates plans to cease operation at Flint Creek by 2038.[11] This would result in a truncated life for any SNCR unit installed of twelve years based on the original compliance date assumptions included in the four-factor analysis. Because SWEPCO's planned retirement date is not enforceable under the SIP, DEQ used twenty years for the cost-effectiveness calculations consistent with EPA guidance.

The commenter's "corrections" for average emission reductions is also incorrect. See responses to comments above.

Lastly, DEQ used a spreadsheet created by EPA for evaluating SNCR at Flint Creek during Planning Period I and updated the inputs. Using EPA's updated SNCR Control Cost Manual

[10] Chapter 1 - Selective Noncatalytic Reduction (epa.gov) See page 1-54

[11] SWEPCO's 2021 Integrated Resource Plan Report to the Arkansas Public Service Commission: https://www.swepco.com/lib/docs/community/projects/DocketNo07-011-USWEPCOIRP12-15-2021Filed.pdf

Cost Calculation Spreadsheet from March 2021 and a 7% interest rate (See Comment 7 for DEQ's consideration of interest rate assumptions), DEQ estimates the cost-effectiveness of SNCR at Flint Creek to be $17,620/ton. See Attachment F1 (Flint Creek_SNCR_UPDATED COSTS). Based on using EPA's new cost calculation spreadsheet for estimating the cost-effectiveness of SNCR at Flint Creek, it appears that DEQ greatly underestimated the cost per ton of installation of SNCR at Flint Creek.

DEQ notes that under SWEPCO's current IRP, the remaining useful life of the plant would be 12 years, not 20. This remaining useful life assumption would increase the cost per ton value for SNCR at Flint Creek. DEQ has determined that the revised calculations continue to support a determination that SNCR is not cost-effective control strategy for Flint Creek.

DEQ will update the cost-effectiveness value of SNCR for Flint Creek based on the new EPA cost-calculation spreadsheet and interest rate corrections.

Comment 41:

One commenter contends that SCR is cost-effective for Flint Creek based on DEQ's analysis. The commenter points to other states second planning period policy decisions regarding cost-effectiveness thresholds to support this assertion. The commenter also states that DEQ "arbitrarily and unreasonably refused […] to provide any explanation for rejecting the Forest Service's recommendation to select SCR for Flint Creek."

Response 41:

DEQ disagrees with the commenter's assertion that the SCR cost of $5771/ton presented in the proposed SIP is cost-effective. See Response 5 for DEQ's consideration of cost-effectiveness thresholds. DEQ has updated the cost-effectiveness calculation for SCR at Flint Creek using the newest spreadsheet and a revised interest rate (See Response 7 for DEQ's consideration of interest rates). The corrected cost-effectiveness value for SCR at Flint Creek is $8641/ton, which greatly exceeds DEQ's cost-effectiveness thresholds for EGU boilers. DEQ notes that under SWEPCO's current IRP, the remaining useful life of the plant would be 12 years, not 30. Therefore, the actual cost per ton value Flint Creek would likely experience would be even greater. DEQ concludes that corrections to the cost-effectiveness calculations for SCR (and a thirty-year equipment life assumption for SCR) at Flint Creek continue to support DEQ's proposed determination that SCR is not cost-effective for Flint Creek. See Attachment F2 (Flint Creek_SCR_Updated Costs).

Although the Forest Service concluded that SCR is a cost-effective strategy for Flint Creek, DEQ does not agree, especially in light of the new analysis above. See DEQ's response to FLM comments in Appendix D-5. DEQ is required to consult with FLMs and consider their feedback, and did so, but the CAA and RHR do not require the states and FLMs to agree.

DEQ will update the cost-effectiveness value for SCR at Flint Creek in the proposed SIP based on the new EPA cost-calculation spreadsheet and interest rate corrections.

Comment 42:

One commenter recommends reviewing Flint Creek for potential upgrades to scrubber/investigation of optimization of NID scrubber system. The commenter asserts that averaging the annual SO_2 emissions from 2012 – 2015, which is prior to the installation of Flint Creek's scrubber, results in a value of 0.424 lb/mmBtu, and averaging the annual SO_2 emissions from 2019 – 2021 inclusive, after the installation of its scrubber, results in a value of 0.055 lb/mmBtu, and concludes that this indicates a scrubber efficiency of approximately 87% ((0.424 - 0.055) / 0.424 = 0.870). Because further optimizing the performance of Flint Creek's NID system would likely be very cost-effective, the commenter suggests that DEQ and Flint Creek investigate the optimization of the NID scrubber system.

Response 42:

The NID scrubber system at Flint Creek was recently installed and has achieved significant reductions in SO_2 emissions since installation. DEQ's decision that further analysis of SO_2 control technologies for Flint Creek is unnecessary is consistent with EPA's Guidance on Regional Haze State Implementation Plans for the Second Planning Period. The Guidance states that EGUs with add on flue gas desulfurization, such as Flint Creek's NID system, that meet an SO_2 emission limit of 0.2 lb/mmBtu for coal-fired EGUs are low enough that it is unlikely that an analysis of controls for such a unit would conclude that an even more stringent control of SO_2 is necessary to make reasonable progress. Flint Creek is required to comply with a much lower SO_2 limit of 0.06 lb/mmBtu. Therefore, evaluation of further optimization of the NID system is unnecessary for Planning Period II.

No changes to the proposed SIP are necessary in response to this comment.

5. Entergy Independence

Comment 43:

One commenter suggested adding into the Administrative Order for Entergy Independence the language, "Any attempt to transfer ownership or operation of the Entergy Independence facility without complying with this Paragraph constitutes a violation of this AO."

Response 43:

DEQ will make the requested change.

Comment 44:

Entergy requested nonsubstantive revisions to the AO for Independence.

Response 44:

DEQ has included the requested revisions in the final AO executed between Entergy and DEQ.

6. Lake Catherine

Comment 45:

One commenter suggested updating Table IV-1 in Chapter 4 to include the fuel oil burning prohibition that is in place for Entergy Lake Catherine, Unit 4, as submitted to EPA for Regional Haze Planning Period I.

Response 45:

DEQ will make the requested change.

E. Federal Land Manager (FLM) and States Consultation

Comment 46:

Two commenters indicated DEQ should address continuous consultation with FLMs, under 40 CFR 51.308(i)(4).

Response 46:

DEQ continues to include FLMs in the Regional Haze consultation through monthly Regional Haze calls with CenSARA states. DEQ has consulted with FLMs throughout this planning period, and will continue to coordinate with FLMs in the implementation of Arkansas's RH SIP for planning period II. In addition, DEQ's five-year progress report is due by January 31, 2025, and DEQ anticipates communications regularly occurring prior to the submittal, starting as early as mid-2023 to ensure that proper consultation has been received during that time. In conclusion, DEQ is meeting and exceeding requirements to effectively consult FLM as required by 40 CFR 51.308(i)(2).

1. DEQ is committed to keeping all federal partners updated and included in conversations and decision-making as it relates to Regional Haze planning and implementation for Arkansas, and will include FLM contacts in any RH decisions or analyses following submission of the proposed RH SIP.
2. Arkansas did not include the response from Texas to its consultation letter dated February 4, 2020 in its consultation summary.

As a follow up to Arkansas's February 4, 2020 correspondence, Texas CEQ scheduled a conference call with Arkansas DEQ on August 6, 2021 to discuss Arkansas's "asks," and to outline the proposal CEQ would be presenting to their Commission. (See App D-2-14) Texas presented a slideshow demonstrating their analyses, which is included in App D. Texas and Arkansas had follow up conversations in CenSARA monthly meetings, and DEQ considers consultation requirements to have been fully met between Arkansas and Texas.

3. The Texas response to Arkansas's consultation letter relied on upcoming retirements at Welsh and Pirkey power plants, but neither Welsh nor Pirkey power plants in Texas is subject to a federally-enforceable retirement commitment.

SWEPCO/AEP has committed to retiring Pirkey in 2023, and has committed to ceasing coal combustion at Welsh in 2028. SWEPCO/AEP filed compliance plans with EPA in response to the Coal Residuals Rule that stated the same. While these are not yet federally enforceable conditions, an EGU plant closure is a years-long planning exercise that is not feasible to abandon or reverse once in motion. When a closure is publicly announced, as is the case with Welsh and Pirkey, the process to conduct the closure is well underway, with concrete agreements in place to adjust for the grid loss in energy generation, and approvals from local Service Commissions.

However, in response to DEQ's release of the pre-consultation draft for Arkansas's RH SIP, TX offered comments that these two sources were not yet under federally enforceable requirements, and explained further that TX had not excluded future emissions from these sources in analyses for TX's RH SIP; therefore, DEQ did include emissions from Welsh and Pirkey in Arkansas's analyses, as presented in the publicly-noticed proposed SIP.

No changes to the proposed SIP are necessary in response to this comment.

Comment 47:

One commenter asserted that DEQ did not analyze or request analysis for Ameren Labadie (MO); Muskogee Generating Station (OK); Ameren Labadie (MO); Cleco Dolet Hills (LA); Ameren Rush Island (MO); Entergy Nelson Generating Plant (LA); City Utilities of Springfield (MO); Grand River Energy (OK); TVA –Shawnee (KY); Thomas Hill (MO); Indiana Michigan Power Rockport (IN); Duke Energy –Gibson (IN); Prairie State Generating (IL); and Hugo Generating (OK). The commenter states that this failure makes Arkansas's SIP unapprovable.

Response 47:

See Appendix D-4. Arkansas requested that other states consider the following sources (all of which were incorrectly identified by the commenter as being unaddressed by DEQ) based on the initial results of the Ramboll Area of Influence study, prepared for CenSARA states for Regional Haze Planning Period II:

States Contacted by DEQ	Facilities Meeting Ramboll AOI Threshold	Identified by Commenter
Indiana	Indiana Michigan Power - AEP Rockport	X
	Duke Energy Indiana LLC - Gibson Genera	X
Illinois	Prairie Generating Station	X
Kentucky	TVA Shawnee	X
Louisiana	Cleco Power LLC - Dolet Hills	X
	Entergy LA LLC - Roy S. Nelson Plant	X
Missouri	Ameren Labadie Plant	X
	Ameren Rush Island Plant	X
	New Madrid Plant - Marston	
	City Utilities of Springfield Missouri - John Twitty Energy Center	X
	Thomas Hill Energy Center	X
Oklahoma	Muskogee Generating Station	X
	Hugo Generating Station	X
	Grand River Energy Center	X
Texas	Martin Lake Electrical Station	
	AEP Pirkey Plant	
	Welsh Power Plant	
	WA Parish Electric Generating Station	

Arkansas DEQ requested that these states consider whether performing a four-factor analysis was appropriate for each of these sources in accordance with 40 CFR 51.308(0(2)(i) and, if so, whether any control measures for sulfur dioxide or nitrogen oxides would be necessary to make reasonable progress towards natural visibility at Upper Buffalo and Caney Creek during the 2021-2028 planning period. DEQ requested that each state share with DEQ the results of analyses, including any technical supporting documentation, and provide an opportunity for consultation on the analysis and each state's long-term strategy early enough in the process for DEQ to provide feedback.

See Appendix C "READ ME" tab for information regarding DEQ's source screening methodology; see also Chapter 2, beginning on page II-14. Texas, Missouri, Oklahoma, Louisiana, and Arkansas DEQ staff were in close contact during SIP development through CenSARA monthly meetings, and openly shared information from ICRs, four-factor analyses, and AOI analyses as it became available through online shared workspaces, email, and videoconferencing. For facilities in Kentucky, Indiana, and Illinois, DEQ maintained contact through regional planning groups, shared workspaces, email, and videoconferencing. All states that DEQ contacted for facility information responded to the request, and additional analyses of interest to Arkansas were shared with DEQ as these became available. Upon receipt of the information, DEQ analyzed any source that met the determined thresholds for inclusion based on the impact of emissions at federal Class I areas. DEQ asserts that these efforts satisfy consultation requirements of the RH program and SIP development.

No changes to the proposed SIP are necessary in response to this comment.

Comment 48:

One commenter asserted that DEQ's treatment of the consultation rule at Section 51.308(f)(2)(ii) is inadequate because there is no indication in Arkansas's Proposed SIP that DEQ performed any real assessment of the likelihood of additional cost-effective controls for these or any sources in other states.

Response 48:

For any sources outside of Arkansas that were above DEQs threshold for impact at a federal Class I area in Arkansas, DEQ reached out to those home states to request that four-factor analyses were considered by the home state (see Chapter 2, pages II-14 and 15). States in receipt of DEQ's requests freely shared these analyses. Arkansas has no authority over sources in neighbor states, and while DEQ did not complete independent analyses of these sources, DEQ reviewed analyses provided by the other states.

No changes to the proposed SIP are necessary in response to this comment.

Comment 49:

One commenter asserts that DEQ did not sufficiently respond the US Forest Service conclusion that SCR would be an effective control strategy at Flint Creek, and that DEQ relied on cost-effectiveness thresholds used for BART analysis despite EPA stating that in most cases BART cost-effectiveness thresholds would not be adequate for determining reasonableness for reasonable progress analyses.

Response 49:

DEQ responded to U.S. Forest Service comments on the pre-proposal draft, including the suggestion to include SCR at Flint Creek. See Appendix D-5.

No changes to the proposed SIP are necessary in response to this comment.

F. Consideration of Visibility in Evaluating Reasonable Progress Strategies

Comment 50:

One commenter provided updated versions of tables and figures to include visibility conditions for Arkansas's Class through 2020, to include the latest visibility data for 2020 that was made available to the Interagency Monitoring of Protected Visual Environments (IMPROVE) steering committee members on February 7, 2022.

Response 50:

DEQ greatly appreciates the effort and contribution of this commenter, and the illustration provided that indicates an expected continued improvement in visibility at Arkansas's federal Class I areas.

No changes to the proposed SIP are necessary in response to this comment.

Comment 51:

Two commenters supported and one commenter disagreed with DEQ's consideration of visibility benefits for reasonable progress determinations. The commenter who disagreed stated that URP should not be a fifth factor in reasonable progress.

Response 51:

DEQ acknowledges and appreciates the support from some commenters on DEQ's consideration of visibility in its determination of what control strategies are necessary to ensure reasonable progress during Planning Period II.

DEQ maintains that the decision to consider visibility is justified and permissible under the Clean Air Act. A state is not limited to solely considering the four statutory factors. In addition to the mandatory factors, DEQ also considered in its evaluation the progress that has been achieved at federal Class I areas, and the anticipated visibility impairment in 2028 at federal Class I areas. This approach is consistent with the flexibility provided to states under the RHR, the recommendations included in EPA's guidance, and the iterative nature of the regional haze program. Consideration of historical and projected visibility progress provides valuable context for the consideration of extent of potential control measures that may be necessary for ensuring reasonable progress. No changes to the proposed SIP are necessary in response to these comments.

DEQ disagrees with the commenter's assertion that DEQ is using the URP as a fifth factor in reasonable progress analyses. Discussion of the URP is intended to demonstrate that 40 CFR 51.308(f)(3)(B) is not applicable to Arkansas for Planning Period II. In fact, U.S. Forest Service commended DEQ for NOT relying on URP in its analysis (See U.S. Forest Service's consultation draft comment letter, included in Appendix D-4).

No changes to the proposed SIP are necessary in response to this comment.

G. Source Selection for Four-Factor Analysis

Comment 52:

One commenter asserts that DEQ's source selection methodology arbitrarily screened out nearly all sources of visibility-impairing pollution from evaluation of cost-effective emission reductions. The commenter cites to language in EPA's July 2021 clarification memo, which explains that states have discretion to reasonably select sources and that the analysis should be designed and conducted to ensure that "source selection results in a set of pollutants and sources the evaluation of which has the potential to meaningfully reduce their contribution to visibility impairment." The commenter contends that DEQ should have selected a number of additional sources to evaluate for potential controls under the four factors based on a Q/d (emissions divided by distance) metric and the commenter's threshold of 5 or higher for this metric. The sources that the commenter suggests DEQ should have evaluated include Plum Point, Georgia Pacific Crossett, Evergreen Packaging in Pine Bluff, Dunn Compressor Station, Albermarle South Plant, and Ash Grove Foreman Cement. The commenter suggests units that should have been evaluated for these sources and potential control strategies.

Response 52:

Nothing in the RHR or EPA guidance documents impose a specific methodology requirement for how the state must select sources for a four-factor analysis. The methodology that DEQ used is discussed in EPA's Guidance for Second Planning Period Regional Haze SIPs, is consistent with EPA guidance, and is more refined than the method that the commenter asserts that DEQ should use. DEQ's methodology more accurately characterizes pollutants and sources "the evaluation of which has the potential to meaningfully reduce their contribution to visibility impairment" than does the commenter's suggested Q/d metric. In fact, EPA's guidance states that the Q/d metric "is a less reliable indicator of actual visibility impact because it does not consider transport direction/pathway, dispersion and photochemical processes, or the particular days that have the most anthropogenic impairment due to all sources." DEQ's methodology is based on an area of influence (AOI) analysis produced by Ramboll US Corporation that takes into account the contribution of visibility impairing pollutants to light extinction at monitors in each Class I area included in the study, transport direction/pathway, actual emissions, and days with the most anthropogenic impairment due to all sources. Therefore, DEQ's methodology provides a much more accurate characterization of visibility impact than does the commenter's proposed methodology. The commenter's assertion that EPA guidance does not support DEQ's source selection methodology is false. DEQ's source selection methodology results in "a set of pollutants and sources the evaluation of which has the potential to meaningfully reduce their contribution to visibility impairment" consistent with EPA's guidance. This is further supported by the fact that the controls included in DEQ's long-term strategy for Arkansas sources alone after consideration of the four factors are anticipated to reduce point source contributions to visibility impairment at Upper Buffalo by 38%, at Hercules Glades by 26%, at Caney Creek by 12%, and at Mingo by 3% based on DEQ's visibility surrogate estimates.

DEQ's source selection methodology was discussed in length during consultation with other states, EPA R6, and the FLMs. Other states adopted similar approaches to DEQ's based on these discussions. EPA R6 suggested some changes, but not a change in approach. DEQ performed a sensitivity analysis based on EPA suggestions. The FLMs originally did a Q/d analysis and sent DEQ a list of sources for further consideration. DEQ considered their suggestion, but ultimately decided to continue to use the more refined methodology, which more accurately characterizes the potential of sources to impact visibility at each Class I area. See Appendix D-5 for responses to FLM comments received on the pre-proposal consultation draft RH SIP.

While DEQ disagrees that the sources that the commenter proposes should have been considered, DEQ did perform a permit review for one of the listed sources as part of a sensitivity analysis requested by EPA. DEQ concluded that evaluation of Albermarle South under the four factors would not produce more potential for meaningfully reducing contributions from Arkansas sources to visibility impairment at Class I areas. See Chapter V of the proposed SIP.

H. Other Comments:

Comment 53:

One commenter suggested that DEQ add annual NOx for 2019 to Chapter IV, Figure IV-2, to make it consistent with other figures in the section.

Response 53:

DEQ has updated Figure IV-2 as suggested.

Comment 54:

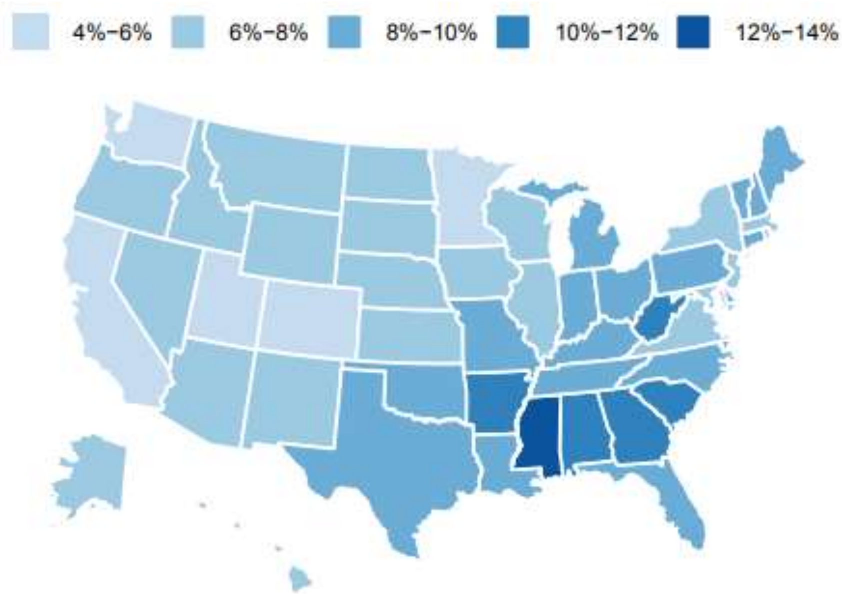
Two commenters recommended addressing environmental justice, as outlined in EPA's July 8, 2021 Clarifications Memo, "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period."

Response 54:

EPA's July 8, 2021 memorandum, "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period," encourages states to consider whether there may be equity or environmental justice impacts when developing their regional haze strategies for the second planning period. DEQ is committed to the fair treatment and meaningful involvement of all Arkansans regardless of race, color, national origin, or income with respect to the development, implementation and enforcement of environmental laws, regulations and policies. DEQ has not identified any negative environmental consequences resulting from implementation of this SIP revision for any group of people. Chapter VII describes DEQ's procedures for ensuring meaningful involvement of all Arkansans. These procedures include providing adequate notice of the final SIP proposal, providing notice of a public hearing, and giving Arkansans the opportunity to provide oral and written comments during the comment period.

In addition, DEQ's strategy for Planning Period II takes economic justice into consideration in its discussion of the cost of compliance for EGUs analyzed under the four reasonable progress factors. Low-income Arkansas households are subject to a statistically higher energy burden than low-income households in other states. In a similar situation with Arkansas, Louisiana, Mississippi, Alabama, Georgia, and West Virginia are also justified (and ethically obligated) to consider the cost of compliance in large-scale planning that affects energy costs for taxpayers. These states all have historically higher rates of poverty per capita than other states, and also have the highest energy-to-income ratios for lower-income families than any other states in the nation. For perspective, low-income households[12] in Arkansas use 36% more electricity than the national average for low-income households, and the energy burden for these families is 10-12% of the family's income. Nationwide, only Mississippi has a higher energy burden at 12-14%,[13] as illustrated in Figure 1.

Figure 1: Low-Income Energy Burden by State (% of Income)[14]



Source: U.S. Department of Energy

[12] Defined in the reference document cited below as those households with 80 percent (or less) of the Area Median Income, as defined by the U.S. Department of Housing and Urban Development

[13] See U.S. Department of Energy's publication: *Low-Income Household Energy Burden Varies Among States — Efficiency Can Help In All of Them*, https://www.energy.gov/sites/prod/files/2019/01/f58/WIP-Energy-Burden_final.pdf

[14] *Ibid.*

Even a small 1-3% increase per month on an electric bill in Arkansas is statistically more significant to ratepayers than in other places in the country The impact on real people and Arkansas families who are already struggling in a quickly-shifting economy and a slow rebound from the COVID pandemic will bear the weight of any investments in EGU capital equipment. While not a deciding factor in selecting sources or determining cost-effectiveness thresholds, it is a real-world condition that DEQ staff, as public servants of the citizens of Arkansas, are bound to consider and to make known to federal partners, who do not have the same perspective for on-the-ground consequences of policy decisions.

Comment 55:

DEQ received one oral comment at the public hearing and three written comments expressing general support for the proposed SIP. DEQ received two comments in support of DEQ's inclusion of Entergy's planned cessation of coal-fired operations at Independence as part of the long-term strategy in the proposed SIP. One commenter supported DEQ's conclusion that new source review would be required if the units at Entergy Independence and Entergy White Bluff were to choose to use a new fuel instead of retiring the units. Three commenters noted their support for DEQ's use of and approach to photochemical modeling to determine reasonable progress goals.

Response 55:

DEQ acknowledges and appreciates these comments.

No changes to the proposed SIP are necessary in response to this comment.